To: Ehren Seybert November 5, 2012
Energy Division
California Public Utilities Commission

Re: Net Energy Metering Cost-Benefit Study

Introduction

SDG&E appreciates the opportunity to provide these comments on the Scope and Methodology of Net Energy Metering ("NEM") Cost-Benefit Study ("Study") as part of the effort to help California achieve a low carbon future. Phase 1 of the NEM Cost Benefit study can provide useful data for Phase 2 to allow full exploration of alternative rate options to NEM that are sustainable with long-term, widespread installation of renewable distributed generation ("DG").

These comments on the Scope of Work, the Methodology, and the Avoided Costs are mindful of the timeframe of the Study and the budget for the Study by suggesting both potential cut backs of the Study as well as additional analysis. The main recommendations include the following:

- Eliminate the 2011 "snapshot" from the Scope of Work
- Limit sensitivities to the dominant solar PV NEM analysis
- Eliminate the "export only approach" from the methodology
- Develop the costs of services provided by utility to NEM customers and the costs of public purpose programs that would otherwise be paid by NEM customers as required by AB 2514
- Adjust the avoided costs to include the impacts of the significant changes to the California electricity grid resulting from the large increase in variable renewable generation that will likely occur in the 2016-2020 time frame
- Adjust the rate impacts of added renewable energy and other AB 32 programs consistent with SB 695

Scope of Work

SDG&E agrees with the Phase 1 Scope of Work as defined on slide 5 of the Energy Division presentation. The Study should fulfill all the requirements of AB 2514 and D.12-05-036 for each of the eligible technologies. However, the Study scope of work should be reduced by eliminating activities that would be of relatively low value to Phase 2 of the Study. One such reduction would be to limit the sensitivity analysis to only the dominant technology, solar photovoltaics (solar PV), and not for each technology in order to allow for a significant number of sensitivities. The amount of DG of all other types compared to solar PV is relatively small and so sensitivities would have relatively low value for these other NEM-eligible technologies.

Another restriction in the Scope of Work would be to eliminate the 2011 "snapshot" analysis. There are a number of assumptions regarding short-term versus long-term avoided costs where there will be significant debate among stakeholders. SDG&E would argue that if such an analysis is done, it should be on a short-term basis as the term "snapshot" implies. In that case, for example, no GHG costs were avoided in 2011 since there was no cap-and-trade program in place, no distribution costs were deferred since distribution planning cycles are 5 years, short-term cost of capacity should be used (a quarter of the long-term capacity value), and actual market electricity costs and actual costs of new renewables should be used for marginal energy costs (will be fairly low due to low natural gas costs, a 20% Renewable Portfolio Standard ("RPS")(instead of 33%), and lower prices for renewables than used in the E3 calculator). This short-term ex-post analysis would seem to take a lot of effort for results that will be disputed by a significant share of the stakeholders regardless of method employed.

Methodology

1. **The "export only approach" should be deleted from the NEM Cost Benefit Study.**

The methodology described on the E3 presentation slide 20 seems appropriate and consistent with the Standard Practice Manual ("SPM") discussion of the Ratepayer Impact Measure (RIM) test, but the "export only approach" is inconsistent with the SPM.

> The benefits calculated in the RIM test are the savings from avoided supply costs. These avoided costs include the reduction in transmission, distribution, generation, and capacity costs for periods when load has been reduced …. The avoided supply costs are a reduction in total costs or revenue requirements …. The costs for this test are the program costs incurred by the utility, *and/or other entities incurring costs and creating or administering the program*, the incentives paid to the participant, decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased.[1] (Emphasis in original)

The SPM indicates the proper calculation is based on "decreased revenues for any periods in which load has been decreased." This approach is consistent with the proposed analysis of what bills would have been without NEM, assuming NEM was critical to the choice to install the distributed generation. The method would look at all generation consistent with AB 2514 because even generation that is not exported reduces measured load and reduces revenues. The "export only approach" does not consider all revenue reductions and is therefore inconsistent with the SPM and should be eliminated.

The E3 presentation, at slide 22, states that the "export only" case "assumes behind the meter customer consumption/production is unchanged by the existence of NEM." In other words, the distributed generation would have been installed regardless of the availability of the NEM. The practice in Energy Efficiency if the measure is undertaken in the 'but-for case,' without the incentive, is to reduce the benefits since the benefits would have occurred in any case. The "net-to-gross ratio" is the measure to reduce benefits in proportion to the percentage of customers that would have undertaken the activity without the incentive. The true "book-end" would be to assign no benefits to NEM since the utility would receive the same avoided cost benefits without the NEM ratemaking if DG production is unchanged. The "net-to-gross" reduction in benefits is the "bookend," not the "export only approach." The "export only approach" should be eliminated from the NEM Cost Benefit Study.

The "export only" case also wrongly assumes residential customers would not have been be subject to demand charges, departing load charges, and/or standby charges if there was no NEM rate schedule. However, rate elements for self-generation were developed in the

[1] SPM, page 13 (Emphasis in original)

commercial and industrial sector in response to self-generation in the form of combined heat and power <u>before</u> renewable DG was commercially available. Therefore, in the commercial and industrial sectors, there are alternate rate schedules for self-generation. The residential sector had no commercially available self-generation technologies before NEM was established, so there are no alternate self-generation rate schedules that include elements to allow the utility to collect for the services provided and for public purpose programs. It does not follow that such rates would not be developed similar to those in the commercial and industrial sector but-for NEM being put in place.

The "export only approach" by definition does not comply with AB 2514 by considering only exports to the grid and not electricity used onsite that reduces a customer's electricity use from the grid. Section 2827.1 (a) of the Public Utilities Code (PU Code) enacted as a result of AB 2514, states, "In evaluating program costs and benefits for purposes of the study, the commission **shall consider all electricity generated by renewable electric generating systems, including the electricity used onsite to reduce a customer's consumption of electricity that would otherwise be supplied through the electrical grid**…" (Emphasis added) The "export only approach" cannot be used in the NEM Cost Benefit Study the CPUC is required to send to the Legislature in compliance with PU Code Section 2827.1 (b).

In addition, as pointed out by E3, "A generator that only offsets load and never exports may nevertheless affect other ratepayers. If the customer's bill are reduced by the direct offset, and some of those revenues were recovering fixed costs associated with serving the customer that do not go away (such as service connection), then those costs are no longer recovered from the customer and will now need to be recovered from other ratepayers."[2] PU Code Section 2827.1(a) specifically states a purpose of the study is "to determine the extent to which each class of ratepayers and each region of the state receiving service under the net energy metering program is **paying the full cost of the services provided to them by electrical corporations, and the extent to which those customers pay their share of the costs of public**

[2] E3, *Net Energy Metering Cost-Benefit Study*, October 16, 2012, page 19.

purpose programs."[3] (Emphasis added) The methodology should be modified to eliminate the "export only approach" since it does not provide complete information on the questions embedded in PU Code Section 2827.1(a), and instead would provide misleading information to the Legislature.

2. **The Study should provide a measure of the cost of services provided by utility and the costs of public purpose programs**

The Phase 1 analysis of NEM should consider the data needs of Phase 2 of the Study. According to the Energy Division presentation slide 4, Phase 2 will "compare alternatives to NEM using a framework that highlights the balance between the financial proposition for customers to install renewable DG and the overall impact to ratepayers." To develop alternative frameworks it is necessary to understand the services utilities provide to NEM customers as well as any services NEM do and/or could provide to the grid, so cost-based rates for the services utilities provide can be considered and the opportunity for value based compensation to NEM customers when they provide services to the grid.

> This approach seems to be the intent of Section 2827.1 (a) of the PU Code, which states,
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> "By October 1, 2013, the commission shall complete a study to determine who benefits from, and who bears the economic burden, if any, of, the net energy metering program authorized pursuant to Section 2827, and to determine the extent to which each class of ratepayers and each region of the state receiving service under the net energy metering program **is paying the full cost of the services provided to them by electrical corporations, and the extent to which those customers pay their share of the costs of public purpose programs**." [Emphasis added]

The Study methodology currently does not propose to quantify any services provided by the utility or any of the costs of public purpose programs and so will not meet the guidelines set forth by AB 2514.

[3] To the extent that Energy Division pursues the "export only approach," it should be separate and distinct from the NEM Cost-Benefit Study to be delivered to the California Legislature and should explicitly state it does not meet the requirements and purpose of AB 2514.

One simple way to meet this requirement of AB 2514 is to calculate the costs of the NEM program if the NEM customer paid the full distribution rate. The distribution rate includes the costs to serve the customer and all public purpose charges. It would be the rate charged if the customer was receiving service from a third party supplier, as opposed to self-generating. The distribution rate would serve as a proxy for the costs of providing distribution service and to pay for public purpose programs, and other charges. Under this rate, non-participating ratepayers receiving service from the balance of utility resources are held indifferent. E3 will already calculate this quantity as part of the study since NEM for wind co-metering and natural gas fuel cells only provides for offsetting the commodity rate, not the full retail rate. Using this measure will be a very simple way to comply with the requirements of PU Code Section 2827.1 (a) under an expansive definition of "full costs."

But SDG&E recognizes that residential rates, as currently structured, lead to larger residential users paying a disproportionate share of customer service, distribution, AB 32, and other public purpose program costs. An alternate that SDG&E would recommend be considered would quantify the costs utilities incur to provide services to NEM customers as well as the manner in which they incur these costs (e.g., fixed, variable, cost drivers, etc.) and develop corresponding demand charges, departing load charges, and standby service costs related directly to the cost of providing services to renewable DG. Tariffs for self-generation are available for the commercial and industrial customers; this exercise would develop comparable cost-based charges for residential self-generation customers. These costs could be quantified by the Energy Division of the CPUC with the assistance of the investor-owned utilities based on General Rate Case Phase 2 filings and provided to E3 for use in the Study. Such an effort could provide significant data that can be leveraged in Phase 2 as well as satisfying the requirements of Public Utilities Code Section 2827.1(a).

Avoided Costs

1. **Avoided Costs Should Reflect the Significant Shift in Load Shapes that will likely Occur in the 2016-2020 Time Frame due to Variable Renewable Energy**

E3 indicated in their presentation that they were not going to update the avoided costs recently approved for use in the 2012-2014 Energy Efficiency applications. By ignoring the large change in expected peak net of variable renewable energy, the avoided capacity costs at various times of the day will be incorrectly calculated. All the CAISO and E3 studies indicate the peak load net of variable renewables will shift to evening hours by as early as 2016. As that shift in peak takes place, the capacity value of solar PV diminishes as it does not produce after the sun sets. The choice to ignore this future reality would seem to invalidate the study results before the study is even undertaken.

Taking this shift in peak load net of variable renewable generation into account should not be difficult since E3 has done analysis of the issue and has calculated the shifting peak for other analyses. Allocation of capacity value across hours should be updated from the use of the top 250 hours on a historical basis pre-2011 data to using expected load net of variable renewable generation to reflect this change in economics over time.

Similarly, though less important than the impact on capacity, is the impact of variable renewable generation on the hourly shape of marginal energy costs. Large increases in variable renewable energy will drive down relative prices in mid-day hours (solar) and middle-of-the-night hours (wind) in the future. E3 has done production cost modeling that could be used to quantify the change in hourly price profiles used in the Study.

2. **Incremental Integration Costs Should Be at Least as Large as Avoided Ancillary Service Costs**

E3 indicated in Slide 31 of their presentation that in 2011 there were no integration costs. The assumption that E3 plans to make is that there are no integration costs for 20 years in the future. This assumption will be made in spite of the massive effort in California to create new structures to accommodate integrating more variable renewables into the electric grid. The CAISO and CPUC will be requiring utilities to obtain additional capacity for flexible ramping, most likely in winter months. The CAISO developed a new load following energy product. The CPUC is considering expensive energy storage to alleviate grid problems created by the intermittency of variable renewable generation. And it is generally acknowledged that more regulation services will be needed. The assumption that integration costs will be zero seems to be a poor assumption. At a minimum, integration costs should be as large as the proposed avoided ancillary service costs E3 has planned to include as an avoided cost (slide 48). Further, a larger value should be included as a sensitivity based on studies where potential integration costs have been quantified.[4]

3. No Deferred Distribution Costs should be the Assumption, with a Sensitivity to Include Deferred Distribution Costs

The allocation of distribution deferred capacity costs across months and hours in the current avoided cost calculations used for energy efficiency are based on the assumption that distribution circuit peaks are coincident with temperature peaks. This assumption, developed over a decade ago, is outdated and shown to be largely inaccurate for a large number of circuits in data developed by ITRON and E3 for the CPUC. From work E3 did for the CPUC on the development of feed-in tariffs, E3 has in its possession utility distribution circuit data that should be used to allocate deferred distribution capacity across months and hours.

Further, given the installation of residential solar DG on circuits is not random, but concentrated on circuits that already have solar DG, future installation of solar DG will likely shift circuit peaks to the evening on those circuits such that it is unlikely that installation of residential solar DG will defer any distribution costs on residential or mixed use circuits in the future. There is a strong empirical case to be made that residential solar DG will not defer distribution costs; SDG&E recommends that “no deferred distribution costs” be the default assumption.

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[4] For example, the PGE Wind Integration Study, Phase II, September 30, 2011 showing integration costs of $11/MWh or earlier Avista and Idaho Power wind integration estimates in the range of $8-$16/MWh.

Distribution peaks on commercial and industrial circuits, on the other hand, do peak in the middle of the day so that it is possible installation of solar DG on these circuits may provide some deferral value. However, these installations tend to be larger and are more likely to cause distribution upgrades. Since none of the solar DG being installed currently has smart inverters, the installation is likely to have caused substantial impacts on reactive power and voltage, requiring distribution system upgrades. These costs may be able to be quantified based on past installations and actual costs of upgrades. Or the costs may be estimated based on smart grid budgets or energy storage cost effectiveness analysis. If the Study does not quantify these costs, the next best solution is to assume they offset any savings in deferred distribution costs. The simple way to handle this situation is to assume zero net costs by excluding distribution upgrade costs and excluding deferred distribution costs.

A sensitivity to the "no deferred distribution cost" assumption could include alternate assumptions on deferred distribution costs and distribution upgrade costs.

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